SURREBUTTAL TESTIMONY OF DEREK P. STENCLIK ON BEHALF OF SIERRA CLUB, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, AND SOUTHERN ALLIANCE FOR CLEAN ENERGY DOCKET NO. 2023-9-E

Q: Please state your name, position, and business address for the record.

A: My name is Derek Stenclik and I am the President of Telos Energy, Inc. My business address is 475 Broadway, Unit 6, Saratoga Springs, NY 12866.

Q: Are you the same Derek Stenclik who previously testified in this docket?

A: Yes.

Q: What is the purpose of your surrebuttal testimony?

A: I reviewed the rebuttal testimony of Ms. Elizabeth Best, Mr. James Neely, Mr. Drew Durkee, Mr. Scott Parker, Mr. Bradley Perricelli, Mr. Andrew Walker, and Mr. Nicholas Wintermantel, collectively referred to as "DESC witnesses." The purpose of my surrebuttal testimony is to address many of the concerns raised by DESC witnesses, clarify misunderstandings from my direct testimony, and more clearly articulate my recommendations for the Commission based on DESC witnesses' rebuttal testimony.

Q: How is your surrebuttal testimony organized?

A: My surrebuttal testimony is organized by topic area and I cover 19 specific issues raised by DESC witnesses in rebuttal. Many of the DESC witnesses provided similar feedback for each issue, and to the extent possible I address their concerns collectively in each response.

Given the number of witnesses providing rebuttal testimony it is not feasible to address each concern. Instead, I focused my attention on the most important comments that have a material impact on the IRP results, findings, and recommendations. If other issues are not addressed in this surrebuttal, it should not be taken as agreement with DESC witnesses' comments.

Q: Do you have any exhibits attached to your testimony?

A: Yes. Exhibit DS-18 and DS-19. Exhibit DS-19 includes corrected Tables 7 and Table 8 from my direct testimony.

Q: Do any of the corrections included in your exhibits change the underlying findings or conclusions from your direct testimony?

A: No, they do not. As discussed later in my surrebuttal testimony, these corrections are minor or simply organizational and do not change the findings of my direct testimony.

Q: DESC witnesses claim that your modeling is flawed because of changes made to certain assumptions. Can you clarify which DESC assumptions were adjusted in your modeling and which ones remained consistent?

A: After reviewing DESC witnesses' rebuttal testimony, it is clear that many of the rebuttal comments are either a misunderstanding of my direct testimony or simply incorrect. In many cases, DESC witnesses incorrectly claim the assumptions in my modeling differed from their own. To the extent possible, my analysis uses the same assumptions used by DESC and I only made a small number of changes to inputs and assumptions. I took this approach to allow for a more direct comparison of DESC portfolios with my own.

To be clear, the discrete changes made in my modeling are outlined in Table 5 of my direct testimony. All other assumptions—including capital cost assumptions, IRA sunsetting schedule, TIA costs and upgrade assumptions, plant retirement schedule, capacity factors of solar, and reliability criterion—are exactly the same in my and DESC's modeling. Simply addressing the concerns I have with some of DESC's assumptions does not mean that I made those changes in my modeling.

Q: After reviewing DESC's rebuttal comments, are there any overarching concerns you would like to address?

A: Yes. I would like to specifically discuss reliability. DESC is right to highlight the importance of reliability for DESC customers and the Commission. Many of the DESC witnesses discussed reliability in their rebuttal comments and each claimed that solar, storage, and DSM resources alone could not reliably replace retiring coal units.[1] I agree that a reliable and adequate power system is one of the most—if not *the* most—important consideration for power system planning. Most of my professional experience has specifically analyzed the ability of clean energy technologies to integrate with the power system while maintaining reliability and resource adequacy.

In his rebuttal testimony, Mr. Neely states: "my primary concern [with Mr. Stenclik's alternative portfolios] is reliability. Replacing retiring coal with solar and storage will not provide for the reliability needs that customers expect and that DESC is committed to provide." Mr. Neely further states that "DESC's Reference

[1] Rebuttal Testimony of James Neely at page 17, Rebuttal Testimony of Elizabeth Best at page 19, Rebuttal Testimony of Scott Parker at page 23, Rebuttal Testimony of Andrew Walker at page 4.

Build Plan adds significant amounts of solar (5025 MW) and storage (1600 MW) but does it without compromising reliability. Solar and storage limits included in DESC's Preferred Build Plan are not arbitrary but enable a reasonable and prudent addition of resources."[2]

In this case, Mr. Neely's stated concern ignores the fact that DESC's preferred plan and my alternative portfolios use the same assumptions to ensure reliability. Mr. Neely claims differences between DESC's preferred plan and my alternative portfolios that simply do not exist. First, both sets of portfolios use declining effective load carrying capability (ELCC) contributions of solar and storage resources and use the same planning reserve margin (PRM) developed in the PRM and ELCC Study, which considered 42-years of historical weather observations. Second, both sets of portfolios were also evaluated in hourly, chronological production cost simulations in PLEXOS to confirm the portfolios are operable and meet spinning reserve and regulation reserve requirements in each hour of the year. Third, both sets of portfolios assume the same transmission upgrades identified by DESC are implemented to maintain reliability after the coal plant retirements.

Additionally, to further address reliability concerns, my testimony included an Enhanced Reliability portfolio which increased the duration of battery energy storage and considered an increase in demand side management—two additional options available to DESC to improve reliability while keeping costs below DESC's preferred plan. In contrast, DESC's portfolio overly relies on a single fuel

[2] Rebuttal Testimony of James Neely at page 30.

for reliability that is predicated on "just-in-time" fuel delivery and upstream gas infrastructure it has no control over.

Q: Based on DESC's feedback related to reliability, did you analyze your portfolios further to ensure they met DESC's reliability needs?

A: Yes. In order to ensure that my portfolios were reliable I worked with expert witness Chelsea Hotaling to evaluate the loss of load expectation (LOLE) of the alternative portfolios from my direct testimony. This effort went further than simply relying on the planning reserve margin (PRM) for reliability as DESC did. Instead, Ms. Hotaling conducted a full probabilistic resource adequacy assessment of my alternative portfolios across 42 years of weather data and hundreds of potential generator outages. Given challenges of representing portfolio effects in resource ELCC and PRM contributions, this "round-trip" analysis is a more robust way to ensure reliability of the resulting portfolio.[3] It should be noted that, despite DESC's claims on the importance of reliability, DESC did not conduct this "round-trip" analysis for their own preferred portfolios.

The "round-trip" modeling process refers to iterations between the resource adequacy model (SERVM) and the capacity expansion and production cost model (PLEXOS). In the first step, Astrape developed the system PRM and resource ELCCs in the PRM and ELCC Study. These values were then used as *inputs* into the capacity expansion modeling conducted in PLEXOS. The resulting portfolios, in this case, were then exported from PLEXOS and used as inputs back in the

[3] Energy Systems Integration Group, *Ensuring Efficient Reliability, New Design Principles for Capacity Accreditation*, Feb 2023, available at https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf

original SERVM probabilistic resource adequacy model. This additional check ensures that the resulting portfolios are resource adequate, as discrepancies can arise in both the input PRM and ELCC as the system resource mix and load profile changes over time.[4]

For the "round-trip" analysis, expert witness Chelsea Hotaling updated the same SERVM model used by DESC and Astrape to conduct the PRM and ELCC Study, to represent a solar and storage replacement of Williams and Wateree. To accomplish this, the following changes were made to the model:

- DESC load was increased to align with the IRP's 2031 monthly peak and energy targets,
- Williams and Wateree coal plants were removed from service (note that Wateree was already removed from service in the PRM and ELCC Study),
- The solar and storage capacities were increased to align with the portfolios considered in my analysis,
- Operational constraints, not previously included in the SERVM database, were added for demand response resources,
- The SEPA Hydro unit was added to the model to align total hydro capacity to DESC's portfolios.

Q: What were the results of this analysis and what does it mean for the reliability of your portfolios?

A: The results of the reliability analysis showed that the Alternative Plan - 2031 Coal Retirement portfolio met the 1-day-in-10-year (0.1 days/year) loss of load

[4] Ibid.

expectation (LOLE) reliability criterion used by DESC. The resulting resource adequacy metrics are provided in Table 1 below, which shows LOLE, loss of load hours (LOLH), and expected unserved energy (EUE).

Table 1: Reliability Metrics for the Alternative 2031 Coal Retirement Portfolio

	LOLE (days/year)	LOLH (hours/year)	EUE (MWh/year
Annual RA Metric	0.04	0.10	78

Table 1 shows that the Alternative Plan - 2031 Coal Retirement portfolio is expected to be reliable across a wide range of weather conditions, load levels, and generator outages. In other words, the Alternative Plan - 2031 Coal Retirement portfolio meets the same stringent reliability criterion used by many utilities and RTOs across the country. *This quantitatively refutes Mr. Neely and others' statements that a portfolio of solar and storage resources would not result in a reliable system for DESC's customers.*

The remaining loss of load events that occur, albeit very rarely (0.04 days per year, or 1-day-in-25 years), occur mostly during outlier system conditions that may not be realistic. For example, 43% of loss of load events occurred in the 1982-1986 weather years. These years experienced extreme cold snaps that are less likely in today's climate than 40 years ago and simulated loads 15-20% above DESC's normal peak load projections. In addition, 68% of loss of load events occurred in the +2 and +4% load forecast error samples, where the load forecast was also increased above DESC's normal projections.

Ms. Hotaling's surrebuttal testimony provides additional discussion of this modeling and further explains the results.

Q: In the rebuttal testimony of Ms. Best (pg 8) and Mr. Neely (pg 24), they dispute the capital costs you assumed for battery storage and solar resources, discuss industry trends for increasing cost, and argue that this shows your plans are not competitive with their preferred plan. How do you respond to those claims?

A: First and foremost, I would like to reiterate that I did not make any changes to the capital costs of solar, batteries, CC, CT or any other resources in my modeling or testimony. I used the exact same assumptions that DESC used and the same ones that were discussed regularly throughout the stakeholder process.

I acknowledge that, like everything else in our economy, renewable technologies and battery storage have gotten more expensive in the past few years. We all feel the impacts of inflation and rising costs, whether for food, technology, automobiles, housing, or energy. The rising costs of renewable energy and battery storage is a function of multiple factors, including overall inflation in the economy, supply chain disruptions, higher interest rates, and increasing labor rates.

There is no disputing that the cost of batteries is higher today than they were two years ago. However, there is no reason to believe this increase is limited in any way to batteries. Supply chain disruption, interest rates, and increasing labor rates affect other resources as well. Cost increases are also seen in combined cycle and combustion turbine technologies, transmission, transformers, pipelines, etc. Any large infrastructure project is going to be affected by these drivers.

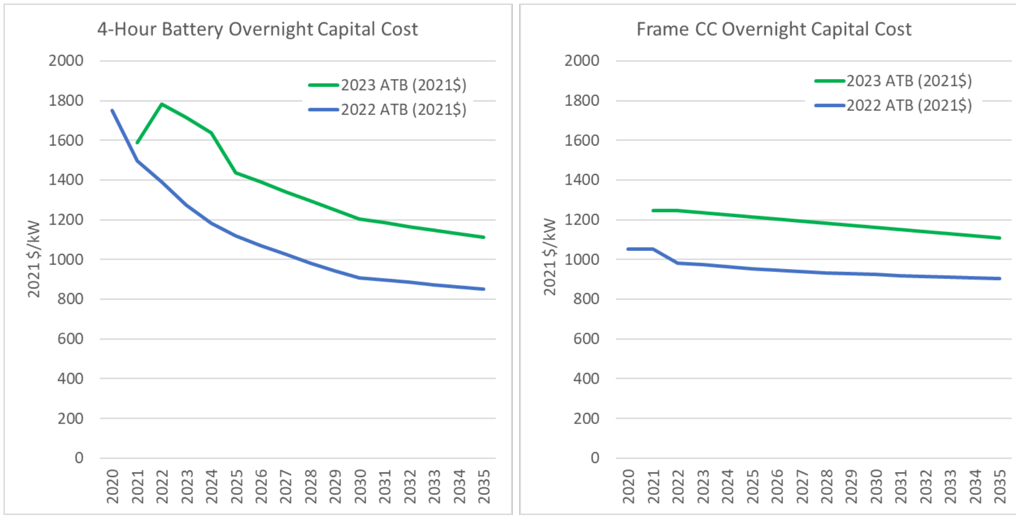
To support its assertions that capital costs have increased, DESC also claims in rebuttal testimony, that the recent NREL Annual Technology Baseline (ATB) cost assumptions (released after direct testimony was filed) are higher by 45%. However, overnight capital cost is only increased by 28-33% after 2025, with additional cost increases attributed to increased financing costs.[5] The Commission should also know that NREL ATB is not an overly optimistic resource, and has actually routinely underestimated cost declines in battery and renewable technologies over the years.[6]

In addition, NREL ATB *also* increased their overnight capital cost for a frame CC resource by 24-27%, almost the same amount as the increase in battery price. The charts provided in Figure 1 below clearly shows that recent price increases are systemic to the overall power industry and the broader economy and not unique to battery storage, as DESC would have the Commission believe.

[5] National Renewable Energy Laboratory, *2023 Electricity Annual Technology Baseline (ATB),* https://atb.nrel.gov/electricity/2023/data

[6] University of California Berkeley, Goldman School of Public Policy, *The 2035 Report, Plummeting Solar, Wind, and Battery Costs can Accelerate Our Clean Energy Future*, June 2020, at page 11, available at https://www.2035report.com/electricity/

Figure 1: NREL ATB Overnight Capital Cost Comparisons for Battery Storage (left) and Frame CC (right) Technologies



DESC suggests that recent inflationary pressure should only be applied to the cost of batteries, but does not discuss increases to other candidate resources. However, DESC's own experience in the Urquhart replacement docket clearly shows that gas resources have been subject to significant inflationary pressure over the past two years.[7] A similar response was provided when comparing costs associated with the Parr project.

In addition, there is no guarantee that battery prices will remain elevated. The U.S. and the global economy are undergoing massive investment in battery production, finding new raw materials, and advancing technology. Much of that manufacturing is happening right here in the US. A case can easily be made that

[7] DESC has stated that "it is not reasonable to compare the costs for the on-going single-unit Bushy Park project to any future project at Urquhart due to the significant difference in timing between these projects; *there have been significant inflationary impacts to all aspects of major generation construction* (emphasis added) since the Bushy Park project contracts were fully executed and when contracts for Urquhart may be fully executed." see DESC response to SCCCL and SACE discovery request 8-5, Docket No. 2021-93-E. Attached as Exhibit DS-18.

prices will *drop* back to pre-pandemic levels, a trend we are already seeing in solar PV panel and raw material prices.[8,9]

In any case, DESC itself chose to use the NREL ATB data (most recent data available at the time of the analysis) and I made no changes to those assumptions. If DESC is looking to use increased battery prices, it should also use increased prices for other candidate resources. I recommend that the issue of capital costs be moved to the next IRP when more information is available from recent pricing and RFPs.

Q: The capital cost of battery technology is an important consideration in your portfolios. Ms. Best (pg 16) and Mr. Neely (pg 24) claim that you used battery costs that appeared too low and reduced them by another 10%. Is this accurate?

A: Absolutely not. As stated in my previous response, *I used the same capital cost assumptions for battery storage as DESC*. No changes were made to the overnight capital cost or financing assumptions except to correct an error in DESC's spreadsheets for battery fixed operations and maintenance costs for 4-hr storage resources using 8-hour storage costs—an error that DESC acknowledged and later corrected.

The 10% reduction included in my analysis reflects the Energy Community bonus available in the Inflation Reduction Act (IRA) that applies to any storage

[8] OPIS, *China Solar Module Prices Keep Diving,* PV Magazine, June 23, 2023, available at, https://www.pv-magazine.com/2023/06/23/china-solar-module-prices-keep-diving/

[9] Ryan Kennedy, *Global Trends for Solar in 2023,* PV Magazine, February 17, 2023, available at, https://www.pv-magazine.com/2023/02/17/global-trends-for-solar-in-2023/

(hybrid or standalone) in or adjacent to a community with a retired coal plant or where a certain percentage of the workforce is in the fossil fuel industry.[10] This is not an arbitrary reduction in the cost assumption, but a simple incorporation of federal incentives available in the IRA. The 10% bonus is actually conservative, as there are *other* potential bonuses—such as domestic content—that could reduce costs further, but which I did not include.

The fact that DESC is ignoring these bonus credits is inexplicable; the Company is essentially leaving ratepayers' money on the table if they pursue the Company's preferred plan. Further, in my modeling, I applied the 10% bonus credits to both my portfolios *and* DESC's preferred portfolios to ensure a like comparison. In other words, I assumed the bonus credits reduce costs for both sets of portfolios, so my portfolios would not have an unfair advantage over DESC's.

Q: If the 10% bonus credits are available in South Carolina, why did DESC omit them from their analysis and what is your response?

A: Both Ms. Best (pg 16) and Mr. Neely (pg 12) in their rebuttal claim that assuming a 10% bonus credit for energy communities is improper because the communities do not overlap with DESC's service territory. This is a flawed assumption for at least four reasons:

1) First, resources do not have to be physically sited in DESC's ratepayer service territory to receive the IRA energy community bonus. Many of DESC's resources are already physically located adjacent or even far from

[10] United States Department of the Treasury, *Treasury Releases Guidance to Drive Investment to Coal Communities,* April 4, 2023, https://home.treasury.gov/news/press-releases/jy1383

ratepayer territory. DESC acknowledged this in the stakeholder meeting on July 12, 2023.[11]

2) Second, while only a relatively small percentage of DESC's service territory is in an energy community, there is far more land available than DESC would ever need. The roughly 2000 MW of battery storage considered in my plan by 2034 would only require approximately 250 acres of land. In contrast, energy communities are estimated to stretch across 1-2 million acres of land in South Carolina.[12]

3) Third, the energy communities in DESC's service territory will only get larger as Williams and Wateree retire.

4) Fourth, I assumed only a portion (1,200 MW) of solar was eligible for IRA bonus credits reflecting that some IRA bonus territories may be in land constrained areas.

As a result, it is appropriate to assume a 10% bonus credit for at least 16% of solar, and I recommend that the Commission require DESC to include bonus credits for standalone battery storage and a large portion of solar and hybrid resources in its modeling. The IRA represents a unique opportunity for new resources and DESC should be making every effort to deliver the benefits of federal subsidies to ratepayers.

[11] DESC IRP Stakeholder Group, Session XII Meeting Minutes, Appendix Table 1 Q&A, Question #11.
[12] Based on visual inspection of the U.S. Department of Energy's Energy Community Tax Credit Bonus map, assuming 5-10% of South Carolina land.

Q: In their rebuttal testimony, Ms. Best (pg 16) and Mr. Neely (pg 13) stated that you assumed tax benefits under the Inflation Reduction Act would not sunset in 2035. Is this accurate?

A: No, this statement is false. Again, I made the same assumptions as DESC on the horizon of the IRA and assumed a sunset in 2035. My testimony merely discussed how this assumption is overly conservative and explained that there is potential additional upside in the portfolios that I developed. By their own assumption, DESC believes that the vast majority of the country will meet the ambitious 85% CO_2 reductions prescribed in the IRA, while they themselves would be far from those levels of reductions.

It should be noted that other utilities are assuming the IRA does not sunset in 2035, but rather extends further in the future. For example, Santee Cooper states that:

> [t]he IRA is scheduled to phase-out after the later of 2033 or the year after the U.S. achieves greenhouse gas reductions prescribed in the IRA. Because there is some uncertainty regarding whether greenhouse gas reductions prescribed in the IRA will be achieved, the 2023 IRP assumes the tax credits are available throughout the Study Period ending 2052.[13]

While I did not modify the IRA sunset date of 2035 in my modeling, I recommend that this assumption be the topic of upcoming stakeholder meetings and to defer this to the next IRP.

[13] Santee Cooper 2023 IRP, available at: https://dms.psc.sc.gov/Attachments/Matter/89ae68ac-b61b-470d-81cc-4f9589a28f9a

Q: In her rebuttal testimony Ms. Best (pg 10) pushes back against a 2029 retirement date for Williams. Can you clarify the retirement dates you evaluated and why you evaluated them?

A: My direct testimony evaluated two retirement dates for the Williams plant: a 2029 and a 2031 date. The 2029 retirement date evaluated in my testimony was based on DESC's original proposed retirement date used in the 2019, 2020, and 2021 IRPs. That date was pushed back to 2031 in part due to inaction.

That being said, my direct testimony was not intended to address the *feasibility* of retiring Williams by 2029. At this point, I do not dispute DESC's assertion that there are timeline risks associated with a 2029 replacement. Rather, the purpose of modeling a 2029 date was to evaluate the *cost implications* of an earlier retirement date and present those findings to the Commission for both 2029 and 2031.

Q: Do the types of replacement resources have any bearing on the timing of coal retirement?

A: Yes, the two studies supporting 2031 as the earliest feasible retirement date—the Coal Retirement Study and the Transmission Impact Assessment (TIA)—use this date due to the long lead-time associated with new gas pipelines and transmission. My alternative portfolio modeling shows that requiring that additional time for replacement gas resources may not be necessary. So even though my analysis was primarily intended to provide a cost analysis of a 2029 and 2031 retirement, it is also possible that it shows how alternatives that could avoid, reduce, or mitigate those pipeline and transmission needs may still allow for an accelerated retirement schedule. These options were simply not evaluated by DESC.

My testimony was also intended to show the wasted ratepayer money associated with a proposed $90M ELG retrofit. DESC's proposal to invest considerable funds to retrofit the Williams coal plant only to retire it two years later shows a clear failure in planning over the last four years when the Williams retirement was first identified in a preferred plan.

Ultimately, the decision about when to retire Williams, either in 2029 or 2031, is the decision of DESC and the Commission, and care should be given to a reliable transition. My analysis shows cost savings for both a 2029 and 2031 retirement date, and DESC and the Commission should utilize whichever case they prefer when evaluating alternatives to DESC's preferred plan.

Q: Many of the DESC witnesses discuss your comments on the TIA study. In your modeling, did you make any adjustments to the transmission costs DESC assumed for the Williams retirement?

A: No, I did not. My analysis assumed the same transmission upgrades and costs developed by DESC. I also never claimed that batteries at Williams would mitigate all of the transmission upgrade requirements. Table 9 of my direct testimony simply calculates what the total LNPV of scenarios, including DESC's, might look like if the TIA costs could be reduced or deferred altogether if battery storage or other resources are strategically located, and uses a reduced TIA cost provided directly from DESC's own analysis.

Q: In their rebuttal testimony, Ms. Best (pg 11), Mr. Neely (pg 17), and Mr. Parker (pg 4) all claim that the 2022 TIA study shows that a battery replacement at Williams is not feasible or cost effective. Is that accurate?

A: No, that is speculation. There is nothing in the TIA that evaluates, quantifies, or simulates why a portfolio of solar and storage resources cannot replace Williams. Despite numerous requests from stakeholders, a full battery replacement at Williams, and/or a smaller addition at Canadys, was simply never evaluated.

DESC's own analysis in the 2022 TIA, in fact, shows that batteries at Williams could have a considerable benefit of reduced transmission requirements, potentially reducing transmission costs by 37% and reducing build time by 33%. Of the remaining transmission upgrades, it is impossible to know whether the costs are attributed to system-level reliability needs, or specific to a 757 MW gas plant at Canadys, or 54% larger than the previous generator at that location. DESC itself attributes much of the remaining transmission costs to the oversized generator at Canadys. Despite repeated requests, DESC refused to evaluate either a larger like-for-like battery replacement at Williams or a smaller generator addition at Canadys. Instead, DESC only evaluated large gas replacement resources and their impacts on transmission needs.

However, it is important for the Commission to understand that **the same transmission upgrades and TIA costs are used in my and DESC's modeling**, and thus do not affect any of the results presented in my direct testimony. My testimony on the omissions in DESC's completed and ongoing TIA was simply intended to highlight the potential benefits of deferred or avoided transmission that could result from battery storage or other alternative transmission technologies strategically sited in the Charleston region.

Q: When you addressed issues with the TIA study and transmission modeling in your direct testimony, you suggested that DESC consider modeling transmission directly in PLEXOS. Mr. Neely (pg 7) and Mr. Parker (pg 11), in their rebuttal testimony, dispute that this is feasible or appropriate. Do you agree?

A: No, I am still confident that modeling transmission in PLEXOS—and throughout DESC's planning processes—would benefit long-term planning for the utility. This would allow the resource selection (PLEXOS LT) and operational analysis (PLEXOS ST) to consider not only the type of resource evaluated, but also the location.

That being said, I never suggested that transmission modeling should be conducted *only* in PLEXOS or that it was a complete alternative to the ACPF tools currently in use for the TIA. I simply suggested DESC leverage the capabilities in the PLEXOS tool that are regularly used throughout power system planning across the industry. I also provided multiple recommendations on how to incorporate transmission—either via nodal analysis or using a zonal topology with transmission interfaces (a Charleston import region would be a prime candidate). Both options would be an improvement. In addition, I offered during the Stakeholder meetings to support DESC—at no cost to the utility—in setting up their model and learning the new capabilities.

In any case, this recommendation has a de minimis impact on the IRP and does not affect any of the results presented in my testimony. At this point, I believe the topic is best addressed via the stakeholder process and in future IRPs.

Q: The topic of solar capacity factors was addressed in Ms. Best (pg 16), Mr. Neely (pg 10), and Mr. Wintermantel's rebuttal testimony. Ms. Best and Mr. Neely claim you adjusted capacity factors of solar resources higher than NREL and historical DESC levels. Is this accurate?

A: Once again, this is a false assertion. I made no changes to the capacity factor or solar profiles developed by DESC, and instead used the exact same ones the Company used in its PLEXOS model. While I discussed the reasonableness of this assumption in my direct testimony, I chose to remain consistent with DESC to limit the number of different variables between the modeling results.

My testimony did discuss how the capacity factor or solar profiles developed by DESC is an overly conservative assumption and biases DESC's results in favor of a gas plant, and I reiterate that statement here. Solar technology has advanced considerably in recent years and there is no reason to assume that new, state of the art, large solar plants needed to replace Williams and Wateree would be similar to small PURPA QFs built in South Carolina in the past. Specifically new, utility-scale PV plants would have increased production for three reasons:

1) New plants would use higher inverter-loading ratios (i.e. adding more panels to the plant) to increase AC output to the grid, most notably during early morning, late evening, and cloudy periods.

2) Single axis tracking systems are now common on many large-scale utility PV projects. These tracking systems change the tilt of the PV panels throughout the day to align with the location of the sun.

3) Bifacial PV panels are solar panels that capture sunlight on both their front and back and can increase total PV production by 10-20% and are increasingly being used in lieu of monofacial panels.

When these parameters are assumed, a solar plant located in Wateree S.C. would increase its capacity factor from 20% to 27% and increase output by 37%.[14] Given decreasing panel costs and technology improvements, it is likely that capacity factors will continue to increase. Duke Energy, for example, recently revised their capacity factor assumption to 28% versus 23.5% assumed by DESC.[15]

These changes could have a material impact on the overall economics of the IRP portfolios. However, I agree with Mr. Wintermantel (pg 5) in his claims that the capacity factor assumption will not change the ELCC of solar significantly, but it could change the ELCC of battery storage because more energy would be available—even on low solar days—to charge batteries. My critique of the ELCC and PRM study was simply that Mr. Wintermantel did not explain the manual adjustments made in his analysis that were done to match DESC's staff expectations.

[14] This calculation was done using NREL PVWatts Calculator, comparing a basic PV installation (1.2 ILR, fixed mount, monofacial panels) to an advanced installation (1.4 ILR, single-axis tracking, bifacial panels).
[15] Duke Energy Carolinas, *2022 Carolinas Carbon Plan: Appendix I - Solar*, page 2, 2022, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=0f3bac67-2d25-4480-beaf-12c93804691b

Q: Many of the rebuttal comments from DESC witnesses addressed your critiques of gas resource modeling. Are there any issues you would like to address?

A: Yes. Based on rebuttal comments I would like to discuss and clarify issues related to CC and CT heat rates, gas plant flexibility, the removal of the CC option in my modeling, and financial incentives, all of which are related to new candidate gas resources.

Q: In Ms. Best (pg 7) and Mr. Neely's (pg 14) rebuttal testimony, they acknowledge that you correctly identified errors in their modeling of heat rates for new CC and CT resources. However, they claim the error is not material to the overall conclusions of the IRP and should not be corrected until a future IRP. Do you agree?

A: I appreciate Ms. Best and Mr. Neely's acknowledgement of this finding, but I do not agree that it is immaterial to the IRP's findings and recommendations. DESC's preferred plan centers around a single resource addition, a 662 MW 2x1 combined cycle resource. The fuel consumption and fuel cost for a combined cycle resource is one of the most important—if not the single most important—assumptions for the candidate resource. The shared CC would represent the second largest thermal generator on DESC's system and, as the newest resource on the system, it would run almost continuously, consuming a large amount of fuel. DESC's heat rate assumptions were 11% lower than reality, significantly reducing the overall fuel consumption—and associated cost—attributed to the plant. The heat rate error alone equates to nearly $19.6 million per year in increased cost associated with DESC's preferred plan.[16]

Mr. Neely states (pg 15) that DESC's error related to heat rates "only" resulted in a 0.56% increase to the LNPV of the Reference Case portfolio, suggesting this difference is insignificant. However, the difference in LNPV in DESC's preferred plan compared to plans that replace Williams and Wateree with only solar and storage resources, are within 1-2% difference in LNPV, so a 0.56% shift in LNPV is a substantial impact.

In addition, I would like to remind the Commission and DESC that I raised the heat rate issue very early in the stakeholder process (January 2023) when first provided the proposed inputs and assumptions for candidate resources. Like many other recommendations and suggestions in the stakeholder process, DESC chose not to implement this in their modeling efforts.

Perhaps most troubling is that the combined cycle and combustion turbine resources are the only resources in the IRP where DESC is using its own internal analysis rather than publicly available resources to develop inputs and assumptions for the candidate resources. If DESC is unable to correctly model the plant's heat rate, why should we be comfortable with their assumptions on capital cost, gas pipeline costs, or other more uncertain inputs?

Lastly, I'll note that most of all the costs omitted due to DESC's error are fuel costs that would be passed directly to ratepayers through DESC's annual fuel

[16] Based on results from the PLEXOS ST Reference Case results, assuming no change to unit dispatch and an 11% increase in fuel cost for the New 2x1 CC 50% shared New CT Frame 2x from 2031-2050.

proceedings. As the Commission knows after 2022, fuel costs can drive significant rate increases when volatile gas prices spike. DESC, on the other hand, will not bear the risk associated with any of these additional fuel costs that it deems immaterial.

Q: In the rebuttal testimony of Ms. Best (pg 17), Mr. Neely (pg 15), and Mr. Walker (pg 16), they take issue with your assumptions on gas plant flexibility and claim they are unrealistic. Do you agree?

A: No. Mr. Neely states that:

> [t]he minimum up and down times [Mr. Stenclik] modeled in his analysis are unrealistic [...], it is not prudent to plan to run these units at the levels Witness Stenclik assumes. To operate these units with these short cycle times would result in high levels of thermal stress, expensive additional maintenance costs and potential long-term reliability issues. None of these additional costs are included in Witness Stenclik's analysis. The longer minimum up and down times assumed in the PLEXOS model reflect how existing units are operated today. To assume otherwise is not a reasonable planning assumption.[17]

Ms. Best and Mr. Walker make similar arguments.

I spent nearly a decade working closely with the gas turbine product teams at GE to understand how to model technical capabilities in production cost models. I take issue with DESC's rebuttal comments on gas plant flexibility for multiple reasons:

1. DESC's oldest gas CT units at Urquhart, Coit, and Parr are being retired and replaced via the Urquhart Replacements All Sources Request for Proposals. These replacement units will be much more capable of cycling on and off and starting faster than DESC's existing resources.

[17] Rebuttal Testimony of James Neely at pages 15-16.

2. The way DESC operates its systems today is not necessarily reflective of the *technical* capabilities of the machines, but rather the *needs* of the system. At today's level of solar integration, there is not a large need to increase unit cycling beyond the parameters in their PLEXOS model. However, as solar integration increases DESC may need to adjust its operations. DESC's remaining CC and CT fleet is relatively new, and numerous publicly available sources cite the capability of being able to cycle on and off within the timeframes I assumed.[18,19,20,21] For example, Intertek—a global leader in thermal plant cycling capabilities and cost—assumes one-hour min up and down times for frame CTs, and two-hour min up times and three-hour min down times for combined cycles, significantly more flexible than my assumptions.[22]

3. I have also conducted over a dozen renewable integration studies nationally, all of which show that leveraging flexibility of the existing CC and CT fleet is the lowest cost mitigation option for integrating variable renewables. Any cost increase attributed to unit cycling and maintenance is grossly exceeded

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[18] Kumar, N. et al,, *Power Plant Cycling Costs,* National Renewable Energy Laboratory, April 2012, https://www.nrel.gov/docs/fy12osti/55433.pdf

[19] GE Energy Consulting, *PJM Renewable Integration Study, Plant Cycling and Emissions,* prepared for PJM Interconnection, LLC, March 31, 2014, https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pjm-pris-task-3a-part-g-plant-cycling-and-emissions.ashx?la=en

[20] International Renewable Energy Agency, *Flexibility in Conventional Power Plants,* 2019, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Flexibility_in_CPPs_2019.pdf?la=en&hash=AF60106EA083E492638D8FA9ADF7FD099259F5A1

[21] Intertek, *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council,* May 12, 2020, https://www.wecc.org/Reliability/1r10726%20WECC%20Update%20of%20Reliability%20and%20Cost%20Impacts%20of%20Flexible%20Generation%20on%20Fossil.pdf

[22] Ibid., page 21, Table 2, Capabilities and Physical Constraints of Fossil Generators, available at, https://www.wecc.org/Reliability/1r10726%20WECC%20Update%20of%20Reliability%20and%20Cost%20Impacts%20of%20Flexible%20Generation%20on%20Fossil.pdf

by the cost savings attributed to reduced fuel consumption and curtailment. The cost of cycling is often attributed to service agreements for maintenance, which are either hours-based or starts-based. Similar to an oil change on a car—which is required based either on mileage or months—the maintenance costs for large unit overhauls can be adjusted based on the hours or starts-based metrics. And, unlike DESC witnesses suggest, this change will not exponentially increase maintenance costs. Instead, like a car, the actual degradation that occurs due to starts and stops is not what is driving the majority of the variable O&M costs for units. The cycling cost and degradation is a function of the amount of time offline, and resources typically count starts as hot, warm, or cold. In a solar-based system, start/stop cycling would see an increase mostly in hot starts, which have the least amount of degradation.

4. While I adjusted minimum up and down times, this constraint is rarely binding in the model. When reviewing the results, the 2031 average hours per start are reasonable in my portfolio relative to DESC's preferred portfolio. CC resources, for example, run for 22-54 hours on average for each start, well in the range of appropriate for this technology. Other resources see limited or no changes. Just because the technical capability is modeled differently, does not mean the model will actually increase cycling: in fact, it did not. Table 2 compares the annual starts, hours online, and hours per start for each unit in 2031 between DESC's preferred plan

and the Alternative Plan - 2031 Coal Retirement portfolio presented in my testimony.

5. The changes introduced on minimum up and down times were done to avoid solar curtailments in the latter half of the study horizon (largely after 2040) and have a small impact on overall costs.

Table 2: Average Operating Hours, Annual Starts, and Hours per Start by Unit

DESC 2031 Thermal Unit Operations	Operating Hours		Annual Starts		Average Hours/Start	
	DESC Preferred	Alt Coal 31	DESC Preferred	Alt Coal 31	DESC Preferred	Alt Coal 31
CEC_CC	6,536	6,505	22	124	297	52
JASPR_CC	8,481	7,229	5	135	1,696	54
URQ_CC	4,520	4,553	75	209	60	22
COP01_ST	1,861	2,882	11	10	169	288
MCM_ST	1,704	1,210	9	8	189	151
URQ03_ST	809	939	14	17	58	55
WAT_ST	0	0	0	0	0	0
WIL01_ST	0	0	0	0	0	0
COIT12_CT	0	0	0	0	0	0
LT_CT	87	57	31	26	3	2
PAR12_CT	795	680	272	280	3	2
WILAB_CT	754	613	148	139	5	4

Overall, although the minimum up and minimum down times are an important consideration, in practice they have a very small impact on the modeling results presented in my testimony. As a result, this topic should not be a primary focus of the IRP discussion. Instead, I recommend that DESC make this a topic of discussion in upcoming Stakeholder Meetings and a key topic of a much-needed third-party DESC Solar Integration Study.

Q: Do Mr. Neely (pg 28) and Ms. Best (pg 18) in their rebuttal testimony accurately describe how and why the shared combined cycle resource candidate was removed from your model?

A: No. Mr. Neely mischaracterizes adjustments I made in modeling by incorrectly asserting that the optimization model would have chosen to construct a 2x1 CC in 2031 to replace Williams were it not for my intervention. This statement ignores the context of this change in my modeling.

In test cases, I found that the shared CC resource was not selected until later in the horizon, 2038, after battery storage and solar resources were optimally selected to replace the Williams and Wateree coal plants. As a result, because the feasibility and economies of scale for a large shared resource in 2038 seemed uncertain, given that DESC, Santee Cooper and this Commission need to make decisions related to the shared resource in the near-term, I opted instead to assess only the CT options for the portfolios presented. In doing so, as I explained in direct testimony, I found that "[b]y removing the shared CC option and instead using smaller CTs, the alternative portfolios are marginally more expensive, but still lower cost compared to DESC's preferred plan."[23]

In my opinion, this change was justified given that a unit with more flexibility to cycle on and off and ramp quicker would be more valuable than a CC resource in 2038. It also bears noting that DESC and the Commission will have numerous opportunities to assess the best way to meet a 2038 capacity need in future IRP proceedings.

In DESC's modeling, however, the shared CC resource is *only* given an option to be built in 2031, thus overly constraining the model. Other resources, in contrast, are allowed to be built throughout the forecast horizon. This constrained

[23] Direct Testimony of Derek P. Stenclik, at page 60.

build date of 2031 gives the model an incorrect "use it or lose it" option that effectively forces selection of the CC resource in 2031. In my model, however, I allowed the CC to be selected at any date in the study horizon after 2031, and PLEXOS does not choose the resources as the optimal way to replace Williams and Wateree by 2031. Instead, it selects the resource later in the study horizon, emphasizing that the 2x1 shared CC is not the cost optimal resource for the near-term replacement of Williams and Wateree.

Q: Is Ms. Best, on pg 18 of her rebuttal testimony accurate in saying that DESC does not have a financial incentive to build new capital projects like a shared combined cycle resource versus alternative options like solar, storage, and DSM resources?

A: No, she is not. Ms. Best inexplicably states that DESC does not have a financial incentive to recover costs associated with new capital projects costing hundreds of millions of dollars despite the fact that DESC is a for-profit, investor-owned utility that earns a guaranteed rate of return on capital investments. Furthermore, DESC does not bear any of the risk associated with the fuel costs required to run the combined cycle. These costs are passed straight through to customers, regardless of fuel price or volatility.

In contrast, many of the solar and storage projects can—and likely would—be developed, constructed, and owned by third-party developers. In this case, the project's cost would be paid for via a power purchase agreement (PPA) where the utility does not earn a guaranteed rate of return on the capital investment. Consumers would benefit from lower cost projects because third-party developers can access lower interest rates and because competitive development tends to result in lower cost energy. DSM resources also lead to lower sales and revenues for the utility.

Ms. Best argues that "DESC's commitment to customers and the public is to provide safe, reliable, affordable and increasingly clean electric service."[24] I would like to clarify that I am not disputing this commitment nor am I asserting that financial returns are the Company's sole priority. I am also not questioning the intent of any individuals. However, it is indisputable that DESC, as a for-profit, investor-owned utility, has a direct financial incentive to favor some resources—namely gas CC and CT resources and associated transmission—over alternative options that may be lower cost for customers.

Q: Both Mr. Neely (pg 19) and Mr. Wintermantel (pg 6) in their rebuttal disagree with your assertion that DESC over-accredited the capacity contribution of gas resources in the planning reserve margin. How do you respond?

A: Mr. Neely incorrectly claims that "[t]here is no gas bias in PLEXOS. In fact, there is a pro solar and battery bias at play here because neither solar nor battery resources are given a forced outage rate in the PLEXOS analysis, as are fossil resources, although both experience forced outages."[25] Mr. Neely is confusing two separate issues when comparing operational data in PLEXOS versus how the resources are accredited for firm capacity towards the reserve margin. In the latter case, gas (and coal) resources are counted at 100% of their capacity towards the reserve margin

[24] Rebuttal Testimony of Elizabeth Best at page 18.
[25] Rebuttal Testimony of James Neely at page 19.

whereas solar and storage resources are counted at the ELCC, and discounted to their contribution to meeting reliability.

Q: How should gas and coal resources be accredited for firm capacity?

A: Thermal resources should, at a minimum, be discounted to their unforced capacity (UCAP), which reduces their capacity contribution respective to the forced outage rate, or the amount of time the unit is unexpectedly unavailable due to unit failures. These are uncorrelated outages which occur at random. For example, at any given time there is a statistical likelihood that a new gas resource may be unavailable about 5% of the time. This number is much higher for older units and coal plants.

However, the real reliability risk is driven by *correlated* outages that occur because generators are more likely to experience failures during extreme cold periods and unavailability due to fuel supply shortages. Not only does this remove a large portion of the thermal fleet at the same time—rather than randomly—it also occurs when load is highest. This correlated reliability risk is the primary concern for ELCC accreditation and the planning reserve margin. For example, if a unit has an *annual* forced outage rate of 5%, the outage rate during extreme cold snaps may be 20-30%.[26]

Finally, coal and gas plants can have discrete outages that can lose hundreds of megawatts of capacity from a single failure. For example, the loss of the large shared combined cycle resource, assuming it is built, would remove 662 MW of capacity, over 13% of DESC's 2031 peak load. On a small system like DESC, this can have disproportionate impacts on loss of load risk.

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[26] Energy Systems Integration Group, *Redefining Resource Adequacy for Modern Power Systems,* 2021, available at, https://www.esig.energy/resource-adequacy-for-modern-power-systems/

For these three reasons, thermal resources should be accredited similarly to solar and storage resources, and it is not adequate to simply claim, as Mr. Neely and Mr. Wintermantel do, that because batteries and gas resources have similar forced outage rates *in PLEXOS* DESC has fairly compared the resources' contribution to reserve margin.

Q: Does DESC include the three risks you identified in the previous response when accrediting solar and storage resources?

A: Yes, they do. Despite Mr. Neely's claim that solar and storage resources were not modeled with a forced outage rate (pg 19), in PLEXOS, DESC actually did include both a random forced outage rate and correlated outage risk. The hourly solar production profiles include the impacts of forced outages because they were calibrated to match the output of actual plant performance. Because solar resources are modular in nature, these outages occur as reduced production throughout the year rather than discrete events. This was included in both the SERVM and PLEXOS models. For storage resources, a 3% forced outage rate was included in SERVM, as referenced in Mr. Wintermantel's rebuttal testimony.[27]

Furthermore, the model *did* include correlated outage risk for both solar and storage resources. The solar resource availability is based on hourly weather conditions across 42 weather years in SERVM, specifically modeling the correlation in solar availability and load throughout the year. For battery storage, correlated outages are represented with charging constraints, which naturally make

[27] Rebuttal Testimony of Nicholas Wintermantel at page 6.

the battery unavailable if other resources on the system are unavailable to charge the batteries.

Q: What is the net effect of these accreditation differences across resources?

A: Capacity accreditation measures a resource's ability to serve load during tight supply conditions and improve reliability. The reason planners do this is to compare the firm capacity contributions (i.e. effective capacity) of various resources and to put them on a level playing field. The objective is to create a technology-neutral exchange rate between resource types so that capacity retirements and additions can be made while maintaining reliability.[28] In DESC's case however, it has overstated the capacity contributions of new gas resources while (appropriately) discounting the contributions of solar and storage resources.

Q: Mr. Wintermantel's (pg 5) rebuttal counters your claim that the storage ELCC was not extended far enough and states that "the penetration analyzed for this study provides sufficient information for critical resource decisions over the next 5-10 years and also provides a basis for the longer-term periods which will have the benefit of seeing future IRP updates before any of those decisions are made." Do you agree with this statement?

A: Under normal planning circumstances, I would agree with this statement, but not in the case of this IRP. DESC currently has very little battery storage on the system, so evaluating 900 MW of new battery capacity would be appropriate to consider incremental additions to the system. However, this IRP is identifying replacement

[28] Newell, S., Spees, K., Higham, J., *Capacity Resource Accreditation for New England's Clean Energy Transition, Report 1: Foundations of Resource Accreditation,* June 2, 2022, available at https://www.mass.gov/doc/capacity-resource-accreditation-for-new-englands-clean-energy-transition-report/download

resources for nearly 1300 MW of retiring coal capacity. Only considering battery storage ELCC out to 900 MW of installed capacity (855 MW of firm capacity) is simply not enough to evaluate a full replacement for the upcoming coal retirements.

This is not a fault of the methodology employed in the study or the results, but simply the design of the study chosen by DESC. At this point in the IRP process, I do not recommend updating the ELCC study, but instead recommending using SERVM to ensure resulting portfolios are reliable (i.e. that they meet the 1-day-in-10 year loss of load criterion).

Q: In their rebuttal comments, Ms. Best (pg 15) and Mr. Neely (pg 25), state that the DSM assumptions used in your Enhanced Reliability Portfolio were 30 times higher than the medium DSM case, 20 times higher than the High DSM case, and nine times higher than Witness Grevatt's calculations. Ms. Best also claims that you did not account for DSM costs. How do you respond?

A: First and foremost, two of the three cases I presented used the exact same DSM assumptions and cost assumptions as the ones used by DESC. It was only in the Enhanced Reliability portfolio that DSM amounts and costs were adjusted to align with Mr. Grevatt's testimony.

Further, when reviewing my use of Mr. Grevatt's DSM levels in Enhanced Reliability portfolio, it appears that DESC made an error by comparing the forecasted *incremental* annual savings attributed to DSM to the *cumulative* DSM savings. After further review, the assumptions used in my modeling align with Mr. Grevatt's calculations. By 2040 the total, *cumulative* impacts of DSM in Mr. Grevatt's testimony represents approximately 6% of load.

In addition, in the Enhanced Reliability portfolio, I included the costs associated with DSM, despite claims by DESC that these were omitted. Specifically, row 14 of the revenue requirements workbook (provided to DESC in discovery) includes "Additional DSM Costs" attributed to Mr. Grevatt's forecast. This added $80M per year in costs and increased the total DSM cost of the portfolio by 320% relative to DESC's assumptions. However, it is important to note that these additional costs are far exceeded by the cost *savings* from this additional investment.

I respectfully refer the Commission and the Company to Mr. Grevatt for any additional information on how those DSM estimates were developed.

Q: In his rebuttal testimony, Mr. Neely (pg 30) identifies issues with Table 7 and Table 8 of your direct testimony and includes a new Exhibit JWN-2. Can you explain any issues or discrepancies in your tables?

A: With respect to Table 7, Mr. Neely is correct that the CO_2 emission values were incorrectly transposed from the PLEXOS results. The CO_2 emissions going across the columns (portfolios) were intended to go down the rows (study years). I appreciate Mr. Neely's detailed review and for catching this transcription error. I would like to clarify for the Commission that this does not represent an error in the underlying modeling, but merely in the presentation of the results in my direct testimony. I have updated Table 7 in Exhibit DS-19.

However, Table 8 was correctly presented except for a typo that actually decreased the Alternative Plan - 2031 Coal Retirement portfolio costs by 0.06%, and Mr. Neely incorrectly made adjustments to the DSM costs. These costs were accurately reflected in my analysis for the Enhanced Reliability portfolio (see my previous response on DSM).

Other changes made by Mr. Neely in Table 8 were simply adjustments to how costs were presented (either fixed, variable, or capital) and his changes merely reclassified how costs were aggregated and presented. The way I segmented those costs intentionally separated and aggregated costs specifically attributed to the coal retirements in one cell. This includes capital cost of new resources, retirement costs of Williams and Wateree, and the TIA costs associated with new transmission upgrades. For clarity, I adjusted the label associated with those costs.

In other words, there was no such error in my underlying modeling. Instead, Mr. Neely and I present the results using different categories. I have updated Table 8 in Exhibit DS-19.

Q: What conclusions have you reached based on your review of DESC rebuttal comments?

A: Many of the rebuttal comments filed by DESC witnesses either mischaracterize points made in my direct testimony or are demonstratively false. While my direct testimony does point out a number of flaws in DESC's analysis or assumptions, most of those were for discussion purposes and were not changed in my quantitative analysis or modeling. In contrast, I limited changes in my modeling to allow for a more direct comparison to DESC.

In addition, many of the comments raised by DESC claim that my portfolios are unreasonable based on cost. Again, I would like to remind DESC and the Commission that my analysis used the same capital cost assumptions and fuel price assumptions as DESC. While I recognize costs have increased since the beginning of the IRP, these cost increases are attributed to all resource types, not just solar and storage.

Finally, I would like to reiterate that portfolios with increased solar and storage can meet reliability needs for DESC and their customers. The portfolios presented in my direct testimony were evaluated using rigorous probabilistic resource adequacy analysis to ensure that the portfolio could meet a wide range of weather, load, and generator outage conditions. Furthermore, I presented additional options of longer duration storage and increased DSM to further increase reliability objectives. My portfolios represent a diverse fuel mix combining gas, hydro, nuclear, solar, and storage resources and can meet or exceed the reliability criterion set by DESC.

Q: Does this conclude your surrebuttal testimony?

A: Yes.

Exhibit DS-18

DESC response to SCCCL and SACE Request 8-5 in Docket No. 2021-93-E

DOMINION ENERGY SOUTH CAROLINA, INC.
SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY'S
EIGHTH SET OF INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS
DOCKET NO. 2021-93-E

REQUEST 8-5:

Does DESC agree that building a single LM 6000 at Urquhart (using reasonable and prudent engineering, construction, and procurement practices for the construction of a single LM 6000) would actually cost approximately $159 million more ($130 million vs $289 million) than the single LM 6000 now under construction at Bushy Park?

a. If so, please explain in detail why constructing the LM 6000 at Urquhart would costs so much more than at Bushy Park, listing and explaining each reason or component of the additional, higher comparative cost.

RESPONSE 8-5:

For clarity, DESC did not prepare the scalable Aeroderivative CT proposal for the Urquhart All Sources Request for Proposals; it was prepared by Dominion Energy Services, Inc. ("DES") Project Construction organization on behalf of DESC.

The scalable LM6000 proposal that was bid into the RFP by Project Construction was developed using firm, lump sum proposals for turbine-generator equipment supply and engineering, procurement, and construction ("EPC") costs for four (4) LM6000 units and was scaled down by removing the major turbine-generator equipment costs for the three (3), two (2), and one (1) unit options. It was not practical for the Project Construction organization to seek firm, lump sum EPC costs for a total of five different options at Urquhart (four combinations of aeroderivative LM6000 units plus the single, least-cost, large frame CT option that was ultimately selected through the RFP process).

This pricing methodology results in conservative pricing assumptions for any solution less than four (4) units.

However, it is not reasonable to compare the costs for the on-going single-unit Bushy Park project to any future project at Urquhart due to the significant difference in timing between these projects; there have been significant inflationary impacts to all aspects of major generation construction since the Bushy Park project contracts were fully executed and when contracts for Urquhart may be fully executed.

Exhibit DS-19

Corrected Tables 7 and 8 from Mr. Stenclik's Direct Testimony

Corrected Tables 7 and 8 from Mr. Stenclik's Direct Testimony

Table 7: Portfolio CO_2 emissions in thousand tons/year relative to 2023 (corrected)

Year	DESC Adj. Preferred Plan	Alt. Coal 2029	Alt. Coal 2031	Alt. Coal 2029 + Enhanced Reliability
2023	9,500	9,500	9,500	9,500
2031	6,095 (-36%)	4,873 (-49%)	5,088 (-46%)	4,409 (-54%)
2040	6,620 (-30%)	5,027 (-47%)	5,208 (-45%)	4,229 (-55%)
2050	7,831 (-18%)	6,827 (-28%)	6,830 (-28%)	5,999 (-37%)

*Values shown are in 1,000 tons

Table 8: Comparison of Levelized Net Present Value by Portfolio (corrected)

LNPV Component	DESC Adj. Preferred Plan	Alt. Coal 2029	Alt. Coal 2031	Alt. Coal 2029 Enhanced Reliability
Total Variable	$868,058	$772,933	$782,919	$704,729
Total Fixed	$618,995	$580,794	$596,809	$657,850
Total Capital & Replacement Costs**	$338,466	$437,289	$414,575	$458,167
Total LNPV	**$1,825,519**	**$1,791,016 (-1.89%)**	**$1,794,303 (-1.71%)**	**$1,820,746 (-0.26%)**

*Values shown are in thousands of dollars
**Capital & Replacement Costs include the capital costs of new resource additions, coal plant retirement costs, and costs associated with the transmission upgrades identified in the TIA

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2023-9-E

In re: Dominion Energy South Carolina, Incorporated's 2023 Integrated Resource Plan (IRP)	**CERTIFICATE OF SERVICE**

I hereby certify that I have served the persons listed on the official service list for Docket No. 2023-9-E, listed below, a copy of the Surrebuttal Testimony of Derek P. Stenclik, along with accompanying exhibits, on behalf of Sierra Club, South Carolina Coastal Conservation League, and Southern Alliance for Clean Energy via electronic mail on this day, August 15, 2023.

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